Decision 02-11-073 November 21, 2002

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation Into the Adequacy of the Southern California Gas Company's and San Diego Gas & Electric Company's (SDG&E) Gas Transmission Systems to Serve the Present and Future Gas Requirements of SDG&E's Core and Noncore Customers.	Investigation 00-11-002 (Filed November 2, 2000)

OPINION ON ADEQUACY OF SOUTHERN CALIFORNIA GAS COMPANY'S AND SAN DIEGO GAS AND ELECTRIC COMPANY'S GAS TRANSMISSION SYSTEMS TO SERVE THE PRESENT AND FUTURE NEEDS OF CORE AND NONCORE GAS CUSTOMERS

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Summary

At the time the Commission initiated this proceeding, there was a gas transmission crisis in San Diego Gas and Electric Company (SDG&E's) service territory that resulted in 17 days of curtailed service and threatened California's energy supply. We now implement new rules and procedures for noncore customers, for SDG&E and Southern California Gas Company (SoCalGas), to prevent the confluence of factors that created the crisis in 2000. In summary, this decision adopts system planning criteria and reliability standards for both utilities; adopts the rule changes set forth in the interim opinion in Decision (D.) 01-06-008 as the permanent changes to Rule 14; allows SDG&E to offer interruptible service at an interruptible rate; orders both utilities to hold open seasons to determine need, timing, and location of capacity additions; adopts a service interruption credit for SDG&E; allows SDG&E to go forward with requested system expansions upon written notice of interest; finds that Line 6900 is a common-use facility, and addresses three outstanding Advice Letters.

In this decision we authorize SDG&E to limit firm noncore service to available firm capacity until additional capacity improvements are completed. We also adopt a 1-in-10 cold-year reliability standard for firm noncore service. With the adoption of this standard, we are requiring SDG&E to proceed with all infrastructure improvements necessary to achieve a 1-in-10 standard for all firm noncore customers. In addition, we have established a mechanism whereby

customers can work with SDG&E to begin preconstruction activities in anticipation of new demand.

The adequacy of SoCalGas' gas transmission system and its ability to serve the needs of its core and noncore gas customers was significantly different than SDG&E's circumstances. Most importantly, there were no curtailments, and no allegations that affiliate preference drove expansion decisions.

In addition, some of the topics under investigation for SoCalGas, specifically, storage, interruption credits; and interstate receipt point capacity allocation concerns were addressed and resolved by the Commission's D.01-12-018 in the Gas Industry Reform Proceeding (GIR), Investigation (I.) 99-07-003. Remaining issues to be addressed include: planning criteria, SoCalGas' pending advice letters, and Line 6900 ratemaking. We adopt a system planning criteria of 1-in-35 for core customers, 1-in-10 for noncore customers, and keep the 1-in-35 for core customers for local transmission. When open seasons are held in combination with these planning criteria, SoCalGas' system should be adequate to serve the needs of its customers.

Background

I. Order Instituting Investigation

On November 2, 2000, the Commission initiated I.00-11-002 into the adequacy of the SoCalGas and SDG&E gas supply and transmission system to provide service to present and future core and noncore customers of SDG&E. This investigation was prompted by high gas demand during the summer of 2000 that threatened gas curtailments for SDG&E's noncore customers. In addition, in June 2000, SDG&E began to provide gas service to a new electric generator (EG), in Rosarito, Mexico,[1] contributing to increased capacity demands.

To address this expanded demand situation, Sempra Energy (Sempra), on behalf of SDG&E, filed Advice Letter (A.L.) 1210-G on August 1, 2000. The A.L. requested emergency review and approval of SDG&E's proposal to temporarily revise the gas transportation service level elections of its large EG customers[2] from firm noncore service to interruptible noncore service. Numerous parties filed protests to A.L. 1210-G. The A.L. and ensuing protests raised a variety of questions and issues requiring further investigation by the Commission, prompting the initiation of I.00-11-002.

II. Advice Letter

In addition to Sempra's A.L. 1210-G, SoCalGas filed four other A.L.s that cover many of the topics within the scope of the OII: A.L. 2929, filed June 21, 2000; A.L. 2966, filed October 12, 2000; A.L. 3002, filed March 7, 2001; and A.L. 3029, filed June 7, 2001. SoCalGas withdrew A.L. 2929 on July 1, 2002. We address the disposition of the remaining three A.L.s in this decision.

III. Bifurcation of the Proceeding

The OII specified certain issues to be addressed in the proceeding relating to SoCalGas and SDG&E's ability to continue providing service to

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[1] Commission Federal de Electricidad's Presidente Juarez Power Plant in Baja California Norte, Mexico (Rosarito) receives its natural gas supply exclusively through Gasoducto Rosarito (GR), a SDG&E affiliate. When SoCalGas and SDG&E submitted Application (A.) 98-07-005 to provide service to GR, their application did not disclose any uncertainty regarding the adequacy of the system to meet the requirements of existing customers in addition to the new, incremental requirements of GR.

[2] Large EG customers were defined as those with an average daily gas usage of greater than 15 million cubic feet.

SDG&E's core and noncore customers. The Commission included SoCalGas in the investigation because SoCalGas provides transmission service to the SDG&E territory. Following two Prehearing Conferences (PHC), and a Joint Issue Statement submitted by the parties, the assigned Commissioner and Administrative Law Judge (ALJ) issued a Scoping Memo adopting the Joint Issue Statement and adding additional topics to the proceeding, including the adequacy of the SoCalGas gas transmission system to serve the needs of its own customers. Because the addition of this topic significantly expanded the scope of the proceeding, and increased the projected time for evidentiary hearings, the ALJ issued a ruling bifurcating the proceeding into two phases: Phase I addressing the adequacy of SDG&E's system, and Phase II covering the adequacy of SoCalGas's system.

IV. Decision 01-12-018

On December 11, 2001, the Commission issued D.01-12-018, in the GIR proceeding, I.99-07-003.[3] This decision adopted a Comprehensive Settlement Agreement (CSA), with modifications, that was supported by numerous parties, including SoCalGas and SDG&E. The CSA primarily applied to SoCalGas, so the Phase I issues relating to SDG&E were not significantly impacted by this decision. However, since the CSA created a system of firm, tradable backbone transmission rights for SoCalGas, the receipt point capacity allocation issues in Phase II no longer needed to be addressed.

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[3] I.99-07-003 was an investigation on the Commission's own motion to consider the costs and benefits of various promising revisions to gas industry regulation.

Phase I Issues: SDG&E

The following parties filed post-hearing briefs on Phase I Issues: Cabrillo I, LLC and Cabrillo II, LLC (Cabrillo); Gasoducto Rosarito (GR); SDG&E and SoCalGas; Office of Ratepayer Advocates (ORA); Duke Energy North America (Duke); Sempra Energy, Sempra Energy Resources (SER), PG&E National Energy Group (PG&E NEG) and Calpine Corporation (Calpine); City of Long Beach (Long Beach); California Independent System Operator Corporation (ISO); Calpeak Power LLC (Calpeak); San Diego County Air Pollution Control District (APCD); California Industrial Group and California Manufacturers & Technology Association (CIG / CMTA); The Utility Reform Network (TURN); and Southern California Generation Coalition (SCGC).

I. Past and Future Planning and System Expansion

The focal point of this OII is whether SDG&E's gas transmission system planning was reasonable and consistent with the Commission's adopted planning criteria. In its 1998 BCAP Application A.98-10-031, SDG&E proposed a resource plan of $25 million. ORA proposed a resource plan of $42.7 million. In D.00-04-060, the Commission ultimately adopted a $31 million plan, which was the amount agreed to by the parties to the SDG&E Joint Recommendation. The Joint Recommendation does not indicate what specific system improvements were agreed to by the settling parties, which system improvements were added to the SDG&E plan, or which were eliminated from the ORA plan.

In the 1996 BCAP, the Commission ordered SDG&E to provide "an explicit non-core reliability standard for its firm service transportation customers that reflects the level of service its system is able to provide" (D.97-04-082, *mimeo.*, at 139). In response to that order SDG&E filed a reliability report based on 1 curtailment in 5 years (1-in-5) firm noncore reliability standard. In the 1998

BCAP, SDG&E continued to advance this 1-in-5 firm noncore reliability standard.

SDG&E curtailed service to firm noncore customers on 17 days between November 2000 and March 2001. SDG&E states that in October 1998, when the BCAP application was filed, it did not contemplate extending firm service to EG customers. SDG&E argues that at that time, SDG&E owned its generation plants and the plants were not sold until April and May of 1999.

We find this a poor excuse for the inadequate planning which caused the service interruptions to SDG&E firm noncore customers over a period of four months in late 2000 and early 2001. Hearings in the BCAP were held in April 1999. SDG&E certainly should have anticipated that the plants were to be sold when they filed the 1998 BCAP Application, and had ample time to update its resource plan prior to hearings to encompass the fact that it would no longer be operating the generation plants. Instead, SDG&E continued to advance a resource plan based on its ownership and operation of the plants and past demand. SDG&E then entered into a joint agreement to adjust the resource plan without regard to necessary and specific system improvements or the changes in operation that were to follow.

Further indication of SDG&E's failure at system planning is evidenced by the fact that in April 2000, a full year later, when all three EGs elected firm service, SDG&E still did nothing to improve its system capacity to meet the new firm load. A review of the transcript from the hearing on the testimony and cross-examination of Ben Montoya, sponsor of Section 2 of the direct testimony of SDG&E and SoCalGas in Phase I, and the exhibits used by SCGC on cross-examination (Exhibits 803 and 804)[4] show that SDG&E knew that curtailments were imminent in 2000. Exhibit 803, SDG&E's Gas Department update for presentation at the Fuels and Purchase Power Team (F&PP) meetings June 22, 1999, and May 4, 2000, demonstrates knowledge by SDG&E that there was a possibility of curtailment in Summer and Winter 2000, increased curtailment likely in 2001 and 2002, substantial possibility of curtailment in 2003 if the Otay Mesa Plant is in service, and that a Miramar enhancement would reduce, but not eliminate curtailment.

The SDG&E meeting and slide presentation on May 4, 2000, took place after the EG customers had signed up for firm service. At that time SDG&E management fully understood the lack of capacity on the system, but chose not to commit money to any expansions without a guarantee of recovery. We find SDG&E's past system capacity planning to be both inadequate and irresponsible.

At this time, we reject TURN's proposal that utility transmission resource plans be considered in a new BCAP. However, it is abundantly clear that SDG&E's past resource planning was not adequate to plan for the evolution of its system load. Therefore, we direct SDG&E and other affected parties to address the resource plan in the upcoming General Rate Care (GRC), or other appropriate proceeding, with great care so that the demands on the system will be met within SDG&E's newly adopted reliability standard for firm noncore service of 1-in-10, cold year conditions.

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[4] Exhibits 803 and 804 were moved into evidence and received on May 22, 2001, by SCGC and are slide presentations of SDG&E's Fuels and Purchase Power Team meetings of June 22, 1999, May 4, 2000, and September 22, 2000.

A key component of the future planning and system expansion plans of SDG&E is the reliability standard adopted for firm noncore customers, including EGs. Parties offered a range of reliability standards for our consideration. For example, SDG&E proposed a standard of one curtailment in every 10 years, normal weather conditions, with each such curtailment lasting no longer than 3 days, (1-in-10) and Duke and Cabrillo advocated one curtailment in every 35 years, using an abnormal cold year peak day as the standard. (1-in-35). As many parties to the OII discussed, the reliability standard is inextricably connected to cost allocation issues and system expansion concerns. Although reliability issues impact cost, cost must not be the sole determining factor in developing system capacity to support the demand on the SDG&E system.

The reliability standard adopted also determines the amount of excess or "slack" capacity that is on SDG&E's transmission system. Many parties argued that there should be at least 15 to 20% slack capacity on the system despite the fact that slack capacity is costly because it provides capacity that is available to accommodate scheduled and unscheduled outages, higher than anticipated peak demands, and increases in new and existing customers' demands. In balancing the concerns over who pays for this excess capacity against the increased reliability the excess provides, the Commission finds it is in the interest of all gas transmission users to adopt a 1-in-10 (one curtailment in ten years), cold year conditions, reliability standard for SDG&E. With this standard, the Commission will not adopt a mandatory slack capacity requirement.

If SDG&E expands its system to meet a 1-in-10, cold year reliability standard, for even its firm noncore customers, SDG&E's transmission system infrastructure should be adequate to meet the needs of both its core and noncore customers. To begin, at the time this investigation was initiated, all of SDG&E's customers were receiving firm service. This decision authorizes SDG&E to only offer firm noncore service when it has the capacity. In addition, on expansion of Line 6900, a line on SoCalGas' system, which flows directly into SDG&E's territory, completed and adds 70MMcfd[5] to southern California. Line 6900's capacity, combined with the Baja Norte pipeline's capacity, will help in easing capacity constraints.

As discussed further below, the Commission is also authorizing a service interruption credit (SIC) for firm customers. SoCalGas had a similar SIC for over ten years, during which time there were no curtailments. When the 1-in-10, cold year reliability standard is combined with the SIC, the additional capacity Line 6900 already provides, and the anticipated relief Baja Norte will bring, the Commission trusts that any system expansion SDG&E might design will reduce or eliminate the likelihood of curtailments, yet not contain excess slack that will result in stranded costs.

To maintain a 1-in-10 reliability standard with the accompanying necessary, excess capacity, SDG&E will have to be realistic, proactive, and regularly update its resource plan. We direct SDG&E to submit a report on its capacity planning, demand forecast, and the status of its expansion projects to the Energy Division (ED) with the first report due on October 30, 2002, and subsequent reports following every six-months thereafter. This report must contain information regarding all requests for firm service that SDG&E was

[5] Million cubic feet per day.

unable to provide and for which it offered interruptible service at interruptible rates instead.

II. Curtailment Protocol

When the OII was initiated in November 2000, the SDG&E gas transmission system had been running at peak capacity on numerous days since July 2000, and gas curtailments to noncore customers seemed imminent. During the week of November 13, 2000, noncore customers suffered curtailments. SDG&E's curtailment protocol is described in Gas Tariff Rule 14 (Rule 14). A.L. 1210-G proposed to alter Rule 14 and temporarily treat SDG&E's three major EGs, Dynegy Marketing and Trade (Dynegy), Duke, and GR[6] as interruptible customers, despite the fact that all three EGs had contracted for firm service. Numerous parties filed protests to the A.L. and SDG&E ultimately withdrew it.

On November 17, 2000, Dynegy and Duke each filed a motion to modify Rule 14. The Commission then solicited comments from the parties on proposals for interim changes to Rule 14. On June 7, 2001, the Commission issued D.01-06-008 to establish an interim order changing the curtailment rules.

The interim order authorizes curtailments to EGs receiving firm service on a pro rata basis and curtails firm service for noncore customers on a rotating block basis in the event the amount of load curtailment from firm service EGs' is insufficient to meet demand requirements.

When SDG&E administered curtailments pursuant to the former protocol, all firm service noncore customers, including noncore commercial and

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[6] GR provides all of the natural gas used to operate the generation plant at Rosarito, Mexico.

industrial customers and EGs, were curtailed pursuant to a rotating block formula. All of the comments support exempting the noncore commercial and industrial customers from the initial curtailment protocol because they were so adversely affected when curtailed, yet their total load was insignificant compared to that of the EGs.

The parties differ extensively, however, on their recommendations for EG curtailments. Cabrillo and APCD recommend that GR, since it is providing service to an EG outside SDG&E's service territory, be curtailed before either of SDG&E's local EG customers. APCD's primary concern is with the air quality in the San Diego area and its fear that if Duke and Dynegy are curtailed, they will continue to generate by burning oil, and compromising air quality and posing health risks to San Diego citizens. Conversely, GR and other parties maintain that GR should be curtailed last since it is the most efficient generating facility. SDG&E, ORA, and SCGC contend that there is no justification for differentiating between the three EGs since they all pay the same rate and take service pursuant to identical conditions. GR agrees with this position and opposes any discrimination between like service classes.

The interim order adopts a pro rata curtailment for all SDG&E EG customers. Pro rata curtailment for the EGs is fair, treats GR equally with the other SDG&E EG customers, and maximizes the amount of gas available to EGs and other customers. We note that as of the date of the issuance of this proposed decision, SDG&E has not had to administer any gas curtailments for any of its customers pursuant to the changes to Rule 14. We will adopt the interim rules on a permanent basis.

A. Limiting Firm Noncore Service

Under its applicable tariffs, SDG&E must offer service to all customers who so request within its service territory. A critical question for this proceeding is whether SDG&E may limit firm noncore service to the amount of firm capacity on the system. Currently, SDG&E does not have the authority under its tariff structure to limit its firm noncore service. If either a new customer or an existing customer wants firm service, SDG&E is presently obligated to provide firm service whether or not there is sufficient capacity to guarantee this level of service. This obligation, coupled with the fact that SDG&E's EG rates for interruptible service and firm service are identical, contributed to the capacity constraints on SDG&E's system that necessitated the gas curtailments in the fall and winter of 2000 and 2001.

When GR signed up for service from SDG&E it requested firm service. Dynegy and Duke, who were not then receiving firm service, soon followed suit. All EGs received firm service at the same rate as interruptible service. SDG&E was obligated under its tariff to convert these customers to firm service, even though it appears that SDG&E did not have enough firm capacity available to guarantee uninterrupted service to these noncore customers. SDG&E has only a finite amount of available firm capacity on its system at any one time. Therefore, it is fair to customers who opt for, and pay for, firm service that their service is firm—and not interruptible by default. As we discuss later in this decision we are also requiring SDG&E to price interruptible service differently from firm service. SDG&E contends that it must be authorized to limit firm service to available firm capacity. If it does not receive such approval, SDG&E maintains that firm service customers for all practical purposes are getting service that is subject to interruption.

ORA supports SDG&E's proposal, as do Cabrillo and Duke. Cabrillo and Duke, however, suggest that once SDG&E upgrades its system to meet the appropriate reliability levels for existing customers, it should conduct an open season to allocate firm service to new firm customers and incremental load. GR also backs SDG&E's recommendation, as long as all noncore customers have an equal, nondiscriminatory opportunity to opt for the service they desire, including firm or interruptible service. CIG / CMTA is willing to support SDG&E's proposal, but only if it doesn't impair the quality of existing firm service.

SCGC is concerned that SDG&E would have no incentive to invest in expanding its system, if the Commission authorizes SDG&E to limit firm service to available firm capacity, and the result will be reduced firm capacity. SER also opposes allowing SDG&E to limit firm service. SER contends that nondiscriminatory treatment within each customer class requires SDG&E to offer firm service to new EG customers, or else they will be barred from entry into the market.

We authorize SDG&E to limit firm service to noncore customers to the firm capacity available, but, as discussed, we have also authorized a reliability standard of 1-in-10. This reliability standard, along with the service interruption credits, will serve as sufficient incentive to SDG&E to continue making investments in its system to meet the needs of its firm noncore customers and to avoid curtailments.

In summary, SDG&E must still provide service to any customer in its service territory that requests service. If a customer requests firm service, and SDG&E determines there is insufficient capacity on its system to ensure firm service, it must offer that customer interruptible service at an interruptible rate.

However, SDG&E must also expand its gas transmission system so that it complies with the 1-in-10, cold weather conditions, for firm noncore customer reliability standard adopted in this decision. As previously indicated in Section I, SDG&E must submit in its semi-annual report to the Energy Division information on all requests for firm service that it was unable to provide and for which it offered interruptible service at interruptible rates instead.

The rate design and rate level of both the firm and interruptible rates will be litigated and decided in the next BCAP proceeding. SDG&E will propose firm and interruptible rates for noncore service in their next BCAP application to be filed on March 17, 2000.

B. Allocation of Firm Capacity in an Open Season

We expect major changes in SDG&E's territory within the next two years. The Baja Norte Pipeline is scheduled to come on line in 2003. This has potential to relieve some of the constraint on the SDG&E system. The Otay Mesa Generating Project is scheduled to begin operation and it may impact the system. Because of the dynamic environment affecting gas demand in the San Diego area, we order SDG&E to initiate an Open Season for firm noncore service within 30 days from the date of this decision. The Open Season commitment will be for a period of 24 months, with all customers bidding by month for any of the 24 months in which they desire to receive firm service. The results will be in effect for 24 months, or until the Gas Industry Reform (GIR) D.01-12-018 is implemented. At that time, SDG&E shall hold another Open Season, so that changes resulting from the implementation of D.01-12-018 can be taken into consideration. The results of the Open Season held after GIR implementation will supercede any remaining time of the initial Open Season.

In the Open Season, customers will be required to commit to the level of their bid, for those months for which they bid. There will be a take-or-pay provision for customer commitments to encourage customers to bid realistically and to prevent gaming on the system. There will be no tradable rights at this time because SDG&E does not have the mechanisms in place to administer those rights. When SDG&E and its customers have a better understanding of how the changes taking place in SDG&E's territory affect them, they can apply for authority to implement tradable rights with a proposed administrative mechanism.

The parties suggested numerous ways to allocate the firm capacity between existing customers and new customers. To avoid favoring any one customer group to the detriment of another, we establish an allocation protocol for firm noncore capacity as follows: After the conclusion of the open season, existing customers will be allocated firm capacity to the demand level of their most recent 12 months. SDG&E must assign any remaining firm capacity to the new incremental load of existing customers and to new customers. If available firm capacity is oversubscribed by the new incremental load of existing customers and that of new customers for any month, SDG&E must prorate the available capacity equally across that customer base.

C. Curtailment Credit

Several parties urge the Commission to adopt a service interruption credit (SIC) or curtailment credit for SDG&E similar to SoCalGas' Rule 23.[7] SDG&E opposes the SIC and argues that the Commission has full authority to

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[7] When the parties briefed the issues for Phase I, SoCalGas's Rule 23 that allowed the SIC was in effect. D.01-12-018 eliminates the SIC for SoCalGas and substitutes a system of diversion penalties and credits in place of the SIC. Elimination of the SIC for SoCalGas was negotiated by the parties to the CSA.

take action against SDG&E if it doesn't live up to the noncore reliability standards. SDG&E argues that a curtailment credit would give the utility an "artificial incentive" to pursue additional pipeline and compressor related capital improvements that would raise transportation costs (SDG&E Opening Brief, p. 20). ORA is not convinced that a curtailment credit is warranted, but states that parties are free to negotiate such a provision.

PG&E NEG and Calpine support a curtailment credit to compensate customers if SDG&E fails to meet its service reliability obligations. SCGC favors the curtailment credit as an incentive tool. In agreement with SCGC, CIG/CMTA argue that "absent a curtailment credit or service guarantee, SDG&E's firm noncore reliability standards would be nothing more than aspirational goals" (CIG/CMTA Opening Brief, p. 5). CIG/CMTA maintain that should SDG&E fail to achieve its reliability standards, there would be no specific penalty, other than a vague promise that Commission might take some unspecified action. We find merit in CIG/CMTA's argument.

Since the inception of the SIC for SoCalGas in D.91-11-025, SoCalGas has not experienced a curtailment necessitating payment of the SIC. It appears the penalty has been an effective measure in motivating SoCalGas to plan its system capacity. It is apparent that SDG&E has not been so motivated in planning the capacity of its system. Increasing convergence of the gas and electric markets makes lack of capacity planning not only a serious problem for gas customers, but impacts SDG&E's electric service as well. We do not find the SIC to be an artificial incentive as SDG&E argues. Instead, we find that it encourages considered capacity planning and related enhancements to meet increased load. The customers of SDG&E cannot be subject to the gas capacity curtailments of 2000 and 2001.

Therefore, although the SIC plan for SoCalGas is no longer in effect, we will adopt a SIC for SDG&E with the same properties as that of the former Rule 23 for SoCalGas. The SIC shall be set at $.25 per therm. We will not consider high demand for gas due to weather conditions to be a force majure event, nor will we place an annual cap of $1 million on SDG&E's curtailment-related obligations. We find that weather conditions must be an integral part of a utility's capacity planning process and will hold SDG&E to the same $5 million cap as was contained in Rule 23 for SoCalGas. We are optimistic that this curtailment credit will work as well as it did for SoCalGas and increase SDG&E's service reliability without penalizing it.[8]

D. Long–Term Commitments and Tradable Rights

SDG&E argues that the key for its effective future planning for noncore customer demand is to require long-term commitments from customers demanding firm service. Specifically, SDG&E wants to require small noncore customers[9] to make a five-year commitment, and large noncore customers[10] to make a 15-year commitment. SDG&E believes these commitments will enable it to pursue least-cost resource planning and eliminate potential investment that are not necessary to meet firm noncore reliability needs.

ORA and TURN were the only parties advocating 15-year commitments. GR, while it concurred with SDG&E's desire to obtain commitments on which to gauge and base expansion needs, contends that 15-years might be impractical for some large, noncore customers. Cabrillo, SCGC, Duke, PG&E NEG, Calpeak, and CIG / CMTA all oppose the 15-year commitment as excessive and unnecessary, because it forces the customers to commit to long term contracts, and penalizes them with harsh take-or-pay penalties. On the other hand, many parties view the five-year commitment as reasonable if the noncore have tradable rights to the capacity.

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[8] In response to the January 7, 2002, ALJ ruling requesting briefing on the GIR, numerous parties argued that since the SIC was eliminated for SoCalGas, it should not be instituted for SDG&E. The Commission is not swayed by this argument, especially in light of how effective the SIC system was as an incentive for SoCalGas, and adopts the SIC as a motivator for SDG&E. For the 10 years Rule 23 was in effect for SoCalGas, there were no curtailments and the utility paid no service interruption credits.

[9] Small noncore customers are those with demand of less than 3,000 therms per hour.

[10] Large noncore customers are those with demand greater than 3,000 therms per hour.

We agree that SDG&E could improve its long-term resource plan forecast if noncore customers are required to make long-term commitments. We note that ORA and TURN agree with SDG&E's 15-year requirement for large EG customers. Some parties are concerned that the EGs will be enticed away from the SDG&E system by competing interstate pipelines, or even by Baja Norte, and then captive customers will be left paying for any stranded costs unless long term commitments are required.

Other parties believe requiring long-term commitments places extraordinary risk on customers who, in a constantly changing and volatile energy market, are expected to project their monthly demand for 15 years and pay a substantial penalty if their projections are too high. Those parties state that allowing for tradable rights would ameliorate this problem.

As mentioned above, however, SDG&E does not have a mechanism in place to manage tradable rights and there are still a number of significant questions concerning tradable rights that need to be aired. The record in this proceeding does not support the Commission's authorization of tradable rights at this time. So we will not require customers to make long-term commitment at this time.

III. Pre-Construction Activities[11] on Written Indication of Interest

SDG&E projects that there is a two-to-four year lag period between the time a need for additional capacity on its system is identified and the time the system is expanded and that capacity becomes available. SDG&E is concerned

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[11] Pre-construction activities include expansion planning, licensing, California Environmental Quality Act activities, and staff labor costs.

that if it initiates pre-construction activities when it receives a written indication of interest, but the customer fails to follow through with a firm commitment, SDG&E would have incurred costs for a project that may be unnecessary and useless. On the other hand, if the utility doesn't begin the pre-construction activities upon the indication of interest, and the customer does follow through with the project, the system expansion will not be ready in time to provide needed new capacity.

To avoid this dilemma, we authorize SDG&E to take the following actions upon receipt of a written indication of interest in firm service:
1) determine if a system expansion is necessary to serve the new projected demand; 2) if so, collect a deposit of 20% of the cost of forecast pre construction activities from the potential customer, or customers, if there is multiple customer interest; 3) undertake pre-construction tasks necessary to meet the projected incremental demand; and 4) if the customer follows through with a firm commitment for service, refund the deposit and commence construction otherwise, keep the deposit. From that point forward, normal ratemaking principles would apply to the expansion project.

IV. Cost Allocation and Rate Design

A. Differential Between Firm and Interruptible Rates

Presently, SDG&E's rates for firm and interruptible service are the same. SDG&E recommends a price differential between these two levels of service to reflect the differing reliability standards associated with each service level. PG&E NEG and Calpine agree with SDG&E. They propose that firm rates should include a monthly demand charge, for the reservation of capacity, and interruptible rates should be all volumetric without a use-or-pay requirement. PG&E Neg and Calpine argue that a price differential between the levels of service would make SDG&E more competitive and facilitate greater pipeline-to-pipeline competition in Southern California.

ORA argues that SDG&E should use the Sempra-wide EG rate for interruptible EG service, and that the Commission should adopt firm transportation rates reflected the actual cost-based transportation rate for service on the SDG&E system as developed in the last BCAP. TURN opposes price differentiation of noncore rates.

Not surprisingly, many of the large noncore customers that benefit from the undifferentiated rate structure by paying no more for receiving an explicit level of reliability, urge the Commission to keep both rates the same. SCGC argues that the current rate structure takes into account the price differentiation between the levels of service by permitting negotiated rates for interruptible service.

Other parties, such as Cabrillo and GR, agree with the general principle that a price differential should exist between true firm service and interruptible service, but GR states that the price differentiation must be disclosed to the customers in advance of the customer’s service election.

We will authorize SDG&E to charge different rates for firm and interruptible service. Offering customers differing levels of service reliability at commensurate rates may allow SDG&E to compete on a more comparable footing with rates of new interstate and international pipelines and may facilitate pipeline-to-pipeline competition in Southern California by enabling customers to evaluate and compare competitive options. We will defer considering proposals on the rate design and rate level of the firm and interruptible rates until the next BCAP. SDG&E will propose rate design and rate levels for firm and interruptible rates in their next BCAP Application.

V. Affiliate Interests

A. Corporate Affiliate Interests

One of the questions within the scope of this OII is whether the corporate affiliate interests of Sempra, the parent company of both SoCalGas and SDG&E, affected SDG&E's transmission service and its system expansions. SDG&E maintains that its corporate affiliate interests have not played a role in its resource planning. SDG&E contends that projects were not delayed, accelerated, added, or subtracted based on information or direction from an affiliate or Sempra. SDG&E argues that it and SoCalGas independently analyze their respective system needs and pursue the appropriate funding for such needs.

Many parties argue that SDG&E's decision to provide firm noncore service to GR compromised its ability to serve the current and possibly the future needs of its existing core and noncore customers. SDG&E does admit that providing service to GR meant less excess capacity was available to serve other noncore customers, but it argues that the same condition would have existed if they had provided service to any new customer.

APCD reviewed the Sempra affiliate list and concludes that Sempra can make more money supplying gas to GR than to the local San Diego EGs. APCD is concerned that because of GR and the demand it makes on SDG&E's system, the probability of gas curtailments to the local San Diego EGs is heightened. If Dynegy and Duke are curtailed, they have the capability of converting to oil; but burning oil contributes to air pollution that can damage the environment and the health and safety of San Diego residents. San Diego air quality standards also limit the amount of oil that can be burned. APCD contends that SDG&E misled the Commission and others when it requested the tariff for GR, and omitted the Duke and Dynegy EGs from its forecasts for gas transmission capacity. SDG&E should have known its "sister affiliate" GR would elect firm service, and that other large EGs would follow. APCD feels that SDG&E should have only offered GR interruptible service, and not put the local San Diego EGs at risk for curtailments.

GR, on the other hand, asserts that the uncontroverted facts in this case demonstrate that SDG&E's transmission service and system expansions have not been affected by Sempra's affiliate interests. GR claims that in SDG&E's tariff application for GR, intervenors argued that, because the contract had been awarded to a Sempra affiliate, the potential for affiliate favoritism required the Commission's strictest scrutiny. In fact, GR, continues, under this strict scrutiny it was determined that GR would be treated like the other EGs, and service to GR should be at the same tariff rates. Conversely, Cabrillo believes that SDG&E took advantage of the need for system expansions to meet its customer's needs, and instead of expanding to meet the existing noncore customers, expanded to provide service to GR. Cabrillo suggests that the Commission must be extra vigilant and alert to any signs of improper arrangements between Sempra and any of its affiliates and must vigorously enforce the affiliate transaction rules.

TURN presents a different analysis. TURN contends that Sempra has long sought to capture the developing Mexican market and tried to prevent a challenge from competing pipelines by offering a discounted rate for utility services. When the Commission denied Sempra's request to offer reduced tariff rates to Mexico, TURN states that Sempra and its affiliates began building the Baja Norte pipeline to serve the largest EG load in Mexico. TURN argues that the Baja Norte pipeline creates a conflict of interest for Sempra between the ratepayers of its regulated utilities and its shareholders' interest in the profitability of the Baja Norte pipeline. TURN fears that when Baja Norte is completed, it will attract significant load—load that could be served by the existing utilities' system. If there are stranded costs for expansions for SDG&E's system because of an exodus to Baja Norte, TURN is concerned that the ratepayers will be at risk for these costs.

B. Baja Norte Pipeline

Inextricably intertwined with the question on the corporate affiliate interests of Sempra is Sempra's decision to go forward with the Baja Norte pipeline expansion. The pipeline project will run from Ehrenberg, Arizona to Tijuana, Baja California. The project was announced June 12, 2000, and an open season was held June 19 to July 14, 2000. A Sempra affiliate owns the 135 miles of pipeline in Mexico.

As stated in the OII, the Commission is concerned that Sempra's decision to go forward with the Baja Norte project was made at the expense of SDG&E's needs for its core and noncore customers. When the project was announced in June 2000, SDG&E clearly knew there existed a lack of capacity on its system and a substantial likelihood of curtailments.

SDG&E claims the Baja Norte pipeline has not affected the system expansions of either SDG&E or SoCalGas. In fact, SDG&E agrees with part of TURN's analysis *i.e.*, when the Commission denied SDG&E's application to offer discounted rates to Mexico, the stage was set for Baja Norte. SDG&E denies that the timing of the Line 6900 Expansion had anything to do with promoting Baja Norte. Instead, SDG&E argues that as soon as the utilities became aware that the increased EG demand was putting a strain on the system, the utilities[12] went forward with the Line 6900 Expansion.

GR contends that the evidence indicates that SDG&E is responsible for its own system resource planning and the Baja Norte pipeline did not interfere with expansion plans. In fact, GR maintains that SDG&E timed its open season to compete with Baja Norte's initial open season to gauge interest in long-term, firm-service commitments to plan for appropriate facility expansions. Even though no customers signed up for SDG&E's open season,[13] GR contends that SDG&E entered into a long-term contract with SoCalGas to encourage SoCalGas to move forward expeditiously with the Line 6900 expansion.

Cabrillo agrees with SDG&E that the Baja Norte pipeline did not affect SDG&E's or SoCalGas' system expansion. Cabrillo contends that the Line 6900 Expansion was needed regardless of the status of the Baja Norte pipeline. However, Cabrillo argues that SDG&E should factor the existence of Baja Norte into account in its future system planning.

APCD questions the "curious chronology" of events in summer 2000 over the announcement of the Baja Norte pipeline and SDG&E's open season, and the fact that Sempra chose to pursue Baja Norte. APCD views this choice as an opportunity for Sempra to maximize its corporate profits by placing its capital investment money in the unregulated business instead of SDG&E.

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[12] SoCalGas owns and operates Line 6900 that extends from the Moreno to the Rainbow compressor stations and transports 90% of SDG&E's gas. The remaining 10% comes from the San Onofre Station, Line 1026.

[13] GR opines that no customers signed up for SDG&E's open season because Baja Norte was offering a superior product.

CIG / CMTA is also interested in Sempra's involvement in the Baja Norte pipeline. CIG / CMTA wonders whether Sempra's involvement creates an incentive for Sempra to benefit from scarcity on the SoCalGas and SDG&E systems.

TURN too, is convinced that the Baja Norte pipeline has affected the utilities' expansion plans. TURN claims SDG&E's open season to compete with the Baja Norte open season was a sham. The SDG&E open season started when Baja Norte ended, required 15-year commitments, and only provided capacity up to 200 MMcfd (half of the projected Baja Norte capacity). In addition, TURN contends that supplying gas through the Baja Norte pipeline provides greater returns for Sempra shareholders at the expense of utility ratepayers. Simply put, TURN states that Baja Norte, which is subject to Federal Energy Regulatory Commission jurisdiction, can net Sempra a higher rate of return than Sempra can make from its Commission-regulated investments in SoCalGas' or SDG&E's service territories. Thus, TURN claims, utility ratepayers will lose revenues and throughput if users flock to Baja Norte and leave the SDG&E system. TURN argues that the only appropriate remedy for the Commission is to eliminate Sempra's conflict of interest between the Commission-regulated utilities and Sempra's unregulated affiliates.

C. Discussion

In the face of conflicting evidence it is difficult to determine with finality whether Sempra allowed its corporate affiliate interest to affect or influence SDG&E's service and system expansions, including the Baja Norte pipeline. What does appear clear, however, is that SDG&E was less than forthright when it applied for its tariff for GR. Specifically, SDG&E represented that the addition of service to GR would not adversely impact the gas customers in San Diego's service territory. Obviously, that was not true.

Even after days of cross-examination, it is also unclear whether Sempra Energy, SER, SDG&E, or SoCalGas violated the letter of any of the affiliate rules. Many of the parties questioned whether the commitment of firm service to GR, coupled with the construction of the Baja Norte pipeline, could ever have been viewed as being in the best interests of SDG&E's core and noncore customers. Sempra Energy, SER, SDG&E, and SoCalGas, on the other hand, insist that they all independently make system expansion plans that are in the best interest of both ratepayers and shareholders.

The only evidence produced at the hearing that belies this assertion is the testimony of Benjamin Montoya on May 22, 2001. Mr. Montoya, in his role as sponsor of Section 2 of the direct testimony of SDG&E and SoCalGas, discusses the presentation he made to SDG&E's F&PP meeting on June 22, 1999.[14] Mr. Montoya testified that although F&PP is a SDG&E committee, Sempra corporate members sometimes do attend and Mr. Reed, senior vice president for regulatory affairs for Sempra Energy did attend this meeting.[15] Thus, based on Mr. Montoya's presentation at that meeting, Sempra had to be aware of the decision by SDG&E to do nothing about expanding its system, despite the fact that there was lack of capacity on the system and curtailments were imminent. This may not show abuse of the affiliate rules, but does point to close integration between Sempra Energy and SDG&E.

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[14] *See* discussion under IV. Past Planning, pp. 11-12.

[15] Testimony of Mr. Montoya, May 22, 2001 (TR 203: 3-15).

VI. Summary Phase I

It is clear we had a gas transmission crisis in SDG&E's service territory that not only threatened curtailments, but actually resulted in curtailed service to firm noncore customers on 17 days between November 2000 and March 2001. The Commission initiated this OII in response to this critical situation from concern over the ability of SDG&E to meet the gas needs of its customers. After all the testimony, exhibits, and briefs are in, the Commission still faces the question: Was it a classic case of conflict of interest when SDG&E, a Sempra owned utility, decided to provide service to GR, a Sempra affiliate, and despite its knowledge that this contract would further strain an already constrained gas transmission system, chose to make no system expansions within its service territory—at the exact same time as Sempra, through another affiliate, was building the Baja Norte pipeline expansion, OR is it only in hind-sight that we can see that the amalgam of unexpected circumstances from about June 2000 through March 2001— such as extreme weather conditions, dry-hydro circumstances, unprecedented electric demand, high electric costs, and constraints on the gas transportation system—converged to create a gas transmission crisis. Although there is insufficient evidence in the record to answer this question or to impose sanctions, we can proceed in this decision to implement new rules and procedures to prevent such a confluence of factors from threatening our gas and electricity supply.

Phase II Issues: SoCalGas

The following parties filed briefs: Cabrillo, California Cotton Ginners and Growers Associations (CCGGA) and Agricultural Energy Consumers Association (AECA), Calpine, Indicated Producers, ORA, Questar Southern Trails Pipeline Company (Southern Trails), SCGC, SoCalGas, and TURN.

I. System Planning

A. Planning Criteria

Much of the documentary and testimonial evidence presented in Phase II focused on concepts for system planning that were substitutes for those advanced in the CSA adopted in D.01-12-018. Almost all of the participating parties testified that they preferred the unbundled approach the CSA promoted, and only proposed less favored suggestions in this proceeding in the event the CSA was not adopted. With the issuance of D.01-12-018 in the GIR, many of the SoCalGas system planning issues from Phase II were rendered moot.

For purposes of this proceeding, the most important change the GIR made for SoCalGas was to create a structure of unbundled, firm, and tradable backbone transmission rights on its system that eliminated the need to consider receipt point capacity allocation. In addition, the GIR provided the following: 1) established a secondary market for intrastate transmission capacity; 2) made SoCalGas at risk for recovery of backbone transmission costs; 3) designated Hector Road as the formal receipt point on SoCalGas' system at which nominations may be made; 4) created firm tradable storage rights with a secondary market for trading those rights; 5) provided for core and noncore customer classes to be balanced separately with no cross-subsidizations; 6) established anonymous monthly imbalance trading; 7) provided for the trading of Operational Flow Order imbalance rights; 8) reduced minimum size requirements and eliminated core market share restriction of the Core Aggregation Transmission program; and 9) eliminated core subscription service.

We must still establish planning criteria and reliability standards for SoCalGas. SoCalGas seeks authorization to plan its backbone transmission system to maintain 15 to 20% annual average slack capacity relative to gas demand under an expected normal weather, normal hydro forecast, as it does now. This plan would supplement SoCalGas' existing 1-in-35 cold year core and 1-in-10 cold year core plus noncore firm service planning standards for local transmission and storage facilities. SoCalGas suggests that the slack capacity should be used for planning purposes, and not as a "specific target to be achieved." Noncore service, SoCalGas argues, has never been designed to be completely uninterruptible.

ORA does not see a need for the Commission to adopt more stringent planning criteria or reliability standards for SoCalGas at this time. Since SoCalGas' system is now unbundled, noncore customers are responsible for determining their individual firm capacity requirements based on their own planning criteria. ORA contends that if noncore customers value enhanced reliability, they can determine how much additional cost for the reliability is justified. If SoCalGas does not have enough capacity to meet noncore intrastate capacity, SoCalGas can determine firm demand by holding an open season, structured like those of the interstate pipelines and PG&E.

TURN argues that the record does not support the adoption of any specific reliability standard, especially the 15-20% slack capacity SoCalGas seeks. TURN advocates uniform standards for system planning for all the utilities on a statewide basis. TURN recommends SoCalGas hold open seasons for noncore customers for capacity expansions and require long-term contracts to recover costs.

Cabrillo proposes making the 1-in-10 reliability standard for noncore peak demand more stringent, in recognition of the benefits to the system and to all customers of adequate transportation capacity. Specifically, Cabrillo wants reliability criteria that meet electric demand during adverse hydro conditions and a slack capacity of 15 to 20%. Cabrillo suggests that a more stringent reliability standard is especially necessary now since the GIR obviates SoCalGas' responsibility to provide firm service on its local transmission and distribution systems to customers who purchase firm receipt point capacity.

Calpine opposes any modification of existing Commission policies that would mandate that SoCalGas maintain any level of excess backbone transmission capacity and instead urges the Commission to continue its policies that permit market forces to drive expansions to the system. Calpine opposes adopting a 15 to 20% excess capacity on the ground that excess intrastate capacity is anti-competitive and will ultimately harm ratepayers.

SCGC proposes a reliability standard that reflects adverse weather conditions, not normal conditions as advocated by SoCalGas, and includes a 15 to 20% slack capacity factor. SCGC suggests that the cost and benefits of this standard can be addressed in the next BCAP proceeding.

Similar to our determinations for SDG&E, we adopt a system planning criteria for SoCalGas of 1-in-10 for noncore customers, and we maintain a 1-in-35 for core customers for local transmission. When open seasons are held in combination with maintaining a 1-in-35 criteria for core and the 1-in-10 criteria for noncore, SoCalGas can use the open season bids to plan expansions of its backbone capacity connected to the receipt points that are fully subscribed.

This planning standard should ensure all SoCalGas customers of adequate transportation capacity, without burdening any customers with the cost of maintaining excess slack capacity. We forecast that SoCalGas will have ample capacity to serve all customer demand under normal conditions through 2006. This forecast is based on the utility's projections for gas demand through 2006, as well as on the predictions that gas demand will decrease, transmission and storage capacity will rise, and gas fired power plants will be more efficient. Therefore, the possibility of curtailments on SoCalGas's system is unlikely.

B. Open Seasons on Local Transmission Lines

The GIR instructs SoCalGas to make new capacity from recent expansions available through open seasons. As a vehicle to determine the need, timing, and location of capacity additions, open seasons were advocated by numerous parties including ORA, TURN, Cabrillo, Calpine, and Southern Trails. ORA and Calpine favor open seasons as the best means for determining the need for additional intrastate capacity. TURN agrees with ORA and Calpine, but with the caveat that capacity planning for core customers should be continued through the regulatory process. Cabrillo sees open seasons as a supplement to the planning process, not as a replacement for it. Southern Trails proposes that SoCalGas hold an open season to determine incremental capacity needs and to identify customers who value this additional capacity and thereby properly allocate it.

SCGC was the only party opposing open seasons. SCGC's contends that open seasons should not be a substitute for appropriate planning criteria. SCGC believes the bidding process that takes place during an open season fails as an indicator of the appropriate size for the system, whereas maintaining a 15 to 20% slack capacity in excess of adverse weather conditions will insure effective gas-on-gas competition.

Open seasons can test the need for further expansions beyond those indicated by application of the planning criteria and can attract customers by offering them flexible terms and conditions and tradable rights to capacity. Open seasons can be a useful source of information about customers' plans, but should not serve as a substitute for thoughtful system planning. When open seasons are held in combination with maintaining a 1-in-35 criteria for core and the 1-in-10 criteria for noncore, SoCalGas can use the open season bids to plan expansions of local transmission lines.

We direct SoCalGas to hold open seasons on its local transmission Line 7000 in the San Joaquin Valley and Line 6902 in the Imperial Valley within 60 days. In the open season, customers may bid for a period of 24 months. Customers may bid on a hour-by-hour basis and for any of the months in which they wish to receive service. Customers will be required to commit to the level of their bid for those months in which they bid. There will be a take-or-pay provision for customer commitments to encourage customers to bid realistically and to prevent gaming on the system.

As we have adopted protocol to allocate capacity for firm noncore customers for SDG&E, we will adopt similar allocation protocol for SoCalGas.

After the conclusion of the open season, existing customers will be allocated firm capacity to the demand level of their most recent 12 months. Any remaining firm capacity must be assigned to the new incremental level of existing customers and to the load of new customers. If available firm capacity is oversubscribed by the new incremental load of existing customers and that of new customers for any period, SoCalGas will pro rate the available capacity equally across that customer base.

C. Optimization of Storage and Transmission

The GIR provides for parallel treatment of backbone transportation and storage, including the unbundling of transportation and storage service, creation of firm, tradable rights for transportation and storage, and development of secondary markets for transportation and storage.

D. Interstate Pipeline Issues

The GIR, by creating firm rights at receipt points, and adding Hector Road as a new receipt point on the SoCalGas system, addressed the interstate pipeline issues.

II. Local Transmission System Issues

A. Advice Letter Issues

SoCalGas seeks approval of four A.L.: A.L. 2929, filed June 21, 2000; A.L. 2966, filed October 12, 2000; A.L. 3002, filed March 7, 2001; and A.L. 3029, filed June 7, 2001. The Energy Division reviewed the A.L.s, the protests and responses, and determined that the A.L.s all related to capacity issues that were the subject of this proceeding. Therefore, no action was taken on the A.L.s while this OII was open, and they will be resolved in this decision.

A.L. 2929

A.L. 2929 is a request for approval of an open season that was held in July 2000, for allocation of firm transmission service to the SDG&E system under SoCalGas' Schedule Nos. GW-SD and GT-SD. Only SDG&E and GR submitted bids in the open season. The combined requested monthly maximum demand quantities for SDG&E and GR were in excess of the available capacity for January, February, October, November, and December. Consequently, the capacities for those months were subjected to pro rata allocation to ensure that the total capacity awarded did not exceed the delivery capacity of the SoCalGas system.

Otay Mesa Generating Company protested the A.L. because it is constructing a 510-megawatt EG plant in SDG&E's service territory, which it expects to have in operation by Spring of 2003.

SoCalGas withdrew this A.L. on July 1, 2002.

A.L. 2966

A.L. 2966 requests approval of an amendment to a Service Agreement between SoCalGas and SDG&E for long-term firm transmission service under Rate Schedule GW-SD. Under this amendment, SoCalGas will expedite construction of two phases on Line 6900 to be completed by Summer 2001 that will add 70 mmcfd of capacity to Line 6900. SDG&E will pay $5.1 million dollars per year for 10 years as an incremental facilities charge (IFC) in addition to any applicable rates and surcharges for interstate transmission service.

ORA protested this A.L. on the basis that the Line 6900 expansion is part of SoCalGas' Commission approved Transmission Resource Plan as a common-use facilities expansion. In the last BCAP, the Commission adopted a Joint Recommendation that included an $18 million investment cost for Line 6900 and said that it was designed to meet load growth expansion on both the SoCalGas and SDG&E systems and is appropriately treated as common-use facilities. ORA recommends that construction commence and that the "deal" between the Sempra affiliates be examined in this OII.

SCGC protested the A.L. because the contract amendment states that if the CSA is adopted in the GIR, SDG&E will pay the IFC, but if not, the utilities will advocate that Line 6900 be treated as a common-use facility. Since the CSA was adopted in the GIR, SCGC's protest is moot.

Dynegy Marketing & Trade (Dynegy) and PG&E NEG filed comments. Dynegy supports the expansion but is concerned about one Sempra affiliate [SDG&E] paying the costs of a line expansion of another affiliate [SoCalGas] made necessary by the service requested by still another affiliate [GR] and the potential to shift the costs of the extension to SDG&E ratepayers.

Dynegy fears that the incremental service contemplated by this A.L. may have the effect of assigning a lower priority to current firm service customers and urges the Commission to examine this issue in the OII.

PG&E NEG recommends that the A.L. be approved with the condition that SDG&E be ordered to temporarily modify Rule 14.[16] PG&E NEG does not believe charging a pro rata share of IFC to a SDG&E EG customer is consistent with the Commission's Sempra-wide rate policy.

SDAPCD and SDG&E support SoCalGas' A.L. 2966.

We direct SoCalGas to withdraw A.L. 2966, because we find that Line 6900 is a common-use facility of both SoCalGas and SDG&E and customers on both systems benefit from its expansion. The cost allocation of expenses relating to the expansion of Line 6900 will be addressed in SoCalGas' next BCAP proceeding; the Application which is to be filed on March 3, 2003.

A.L. 3002

A.L. 3002 requests approval to implement the results of an open season for firm transportation service which was held for noncore and noncore-eligible customers in the area of SoCalGas' system south of Niland Station (Line 6902) in Southern Imperial Valley. This request proposes deviations from Tariff Schedule No. GT-F, Firm Intrastate Transmission Service; Schedule No. GN-10, Core Service for Small Commercial and Industrial; and Rule No. 23, Continuity of Service and Interruption of Delivery, based on the results of the open season. Capacity was pro rated for months that were oversubscribed. SoCalGas first set aside capacity for core customers and

[16] This issue is moot since the Commission prescribed changes to Rule 14, curtailment protocols, in the Interim Decision, D.01-06-008, issued June 7, 2001.

Distribuidora de Gas Natural de Mexicalli (DGN), a Sempra affiliate, who is increasing usage this year under an existing contract agreement.

Imperial Irrigation District (IID), CMTA, and CCGGA filed protests. IID and CMTA protest on the basis that SoCalGas denied on-system Imperial Valley customers their tariffed right to elect firm full requirements service without seeking or getting any prior approval or authorization from the Commission. CCGGA protests on the basis that SoCalGas is seeking to eliminate full requirements service and none of the remaining options offered by SoCalGas under the open season will benefit its members.

The period covered by the open season was June 2001 through May 2003. SoCalGas is directed to hold an open season in the Southern Imperial Valley within 60 days in accordance with Section 1, Part B, open season of the Decision. We direct SoCalGas to withdraw A.L. 3002.

A.L. 3029

A.L. 3029 requests approval to implement the results of an open season for firm transportation service that was held for noncore and noncore-eligible customers in the San Joaquin Valley (Line 7000). The A.L. requests deviations to Tariff Schedules GT-F, Firm Intrastate Transmission Service; GN-10, Core Service for Commercial and Industrial Service; and Rule No. 23, Continuity of Service and Interruption of Delivery.

Protests were filed by CCGGA, Tule River Cooperative (cotton ginners and prune dryers), AECA and SCGC. Protestors argue that the tariff deviations requested by SoCalGas are violations of Code Sections 454 and 455 since SoCalGas is attempting to subject them to use-or-pay charges. SCGC further argues that this A.L. should be rejected because SoCalGas is taking two inconsistent positions: the tariff allows them to not offer full requirements service, yet the A.L. asks the Commission to excuse them from having to offer full requirements service.

As with A.L. 3002, the Commission finds that A.L. 3029 is no longer timely and we direct SoCalGas to withdraw the A.L. The term of the open season was from August 2001 through July 2003. We direct SoCalGas to hold an open season in the San Joaquin Valley within 60 days of this decision in accordance with Section 1, Part 13, open season of this decision.

B. Local Transmission System Expansion Policy

SoCalGas can plan the timing and location of capacity additions through a combination of various mechanisms including a thorough analysis of the subscriptions to its open season, adherence to a system planning criteria of 1 in 10 for noncore customers and 1 in 35 for core customers for location transmission, and nonbonding expressions of interest in long-term agreements in the event customer commitments exceed available capacity in any of the 24 months of the open season. SoCalGas is directed to present a detailed Resource Plan in the next GRC or BCAP.

C. Service Interruption Credit

The GIR/CSA specifically eliminates the SIC for SoCalGas.[17]

III. Receipt Point Capacity Allocation

The allocation of receipt point capacity is one of the key issues addressed in the CSA. Now that the CSA has created a system of unbundled, firm, and tradable backbone transmission rights on the SoCalGas system, all other proposals are superceded.

[17] Section 1.1.3.4 of the CSA, adopted with modifications, in the D.01-12-018.

IV. Ratemaking Issues

The CSA states that SoCalGas' rates cannot change until 2006. However, in this decision we determine that Line 6900 is a common-use facility of both SoCalGas and SDG&E.

The history of the expansion of Line 6900 and the competing positions on the appropriate cost allocation is set forth in great detail in D.98-03-073. Prior to the 1993 BCAP, Line 6900 was treated as an exclusive use facility of SDG&E and it was assigned 100% of the costs. In the 1993 BCAP, the Commission approved a joint recommendation of SoCalGas, SDG&E, and ORA that treated Line 6900 as a common-use facility.

Line 6900 is part of an integrated system that serves SoCalGas' retail customers in Riverside County and SDG&E as a wholesale customer. The question is who should pay for this line expansion. Should the costs for the Line 6900 be treated as a common-use transmission facility and allocated equally among all customers of SoCalGas, including SDG&E; allocated only to SDG&E customers; or allocated exclusively to SDG&E's noncore customers. The issue of cost allocation is controversial because at the time Line 6900 was designed and built it was projected to serve a shortage of capacity on SDG&E's system. However, the Commission has since determined, in two previous decisions, that Line 6900, benefits all SoCalGas customer-including SDG&E and its customers.

ORA and TURN fear, however, that large noncore customers, primarily the EGs, will leave Line 6900 when the Baja Norte pipeline project is completed in a few years, and then EG customers will no longer pay for Line 6900. Instead, ORA and TURN contend that captive ratepayers will be subsidizing this line expansion that will provide no benefit to them in the foreseeable future. In fact, ORA and TURN recommend that Line 6900 be priced incrementally and recovered from SDG&E's noncore customers through a surcharge that amortizes the capital cost over a 12-month period.

The CSA states that SoCalGas cannot change its rates until 2006. SoCalGas argues that while Line 6900 is a common-use facility, the Commission should sanction what it considers a short-term solution to the ratemaking dilemma created by the CSA. SoCalGas requests approval of an amendment to a contract with SDG&E which requires SDG&E to pay SoCalGas an Incremental Facilities Charge (IFC) of $4.7 million each year during the term of the CSA in exchange for providing firm transportation service for 10 years at a level that required expansion of Line 6900.

In finding that Line 6900 is a common-use facility, we have instructed SoCalGas to withdraw A.L. 2966. SoCalGas knew when it expanded Line 6900 that the CSA would not allow it to change rates until 2006. It signed the CSA in April 2000 and the contract amendment requiring SDG&E to pay an IFC in October 2000. We do not believe that SDG&E customers should bear the sole responsibility – even for four years of an expansion that benefits both SoCalGas and SDG&E customers. We defer the mechanics of cost allocation of the expansion of Line 6900 as a common-use facility to the BCAP, to be filed in March, 2003.

In D.00-04-060, the Commission approved a settlement treating the Phase 3 and 4 costs of the Line 6900 expansion as common costs paid by all customers. Parties raised the same arguments in that proceeding against treating the expansion costs as common costs as they did in the instant proceeding. We will not change the treatment of expansion costs of Line 6900 here. Line 6900 is a common facility and the costs are to be allocated across both SoCalGas' and SDG&E's service territories, and for all customers.

V. Summary Phase II

The three A.L.s are all moot or no longer timely because of the passage of time. The ratemaking issue for Line 6900 is resolved in this decision by the finding that the line expansion is a common-use facility and the costs are to be allocated across both SoCalGas' and SDG&E's service territories and for all customers. The cost allocation mechanism is to be decided in the upcoming BCAP.

Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the rules of Practice and Procedure. Comments were filed on September 9, 2002 by Cabrillo I, LLC, and Cabrillo II, LLC, Calpine and PG&E NEG, ORA, SCGC, and SDG&E, Sempra Energy, SER, SoCalGas, and TURN. Reply comments were filed on September 16, 2000 by Cabrillo I, LLC and Cabrillo II, LLC, Calpine & PG&E NEG, Duke Energy North America, ORA, PG&E, SDG&E, SoCalGas, SCGC, and TURN. Comments merely repeating arguments made in briefs were not considered.

1. SDG&E, Cabrillo I, LLC, and Cabrillo II, LLC, Calpine, and PG&E NEG, ORA, and SCGC commented on the discussion of firm and interruptible rates. SDG&E requested that the Commission not use a pronouncement in this proceeding on the rate level or rate design for firm and interruptible rates that it has ordered for large noncore customers, but requests deferral of specific rate differentiation proposals until the next BCAP. Upon review we agree with SDG&E's recommendation and modify the decision accordingly.
2. SDG&E maintains that the adoption of a SIC presents the possibility of punishment without crime. SDG&E requests that if the Commission must adopt an SIC, it lower the

annual cap to less than $1 million to reflect its much smaller size relative to SoCalGas. We disagree on both issues. Adopting a SIC is not a "punishment without a crime" as the SIC will not be assessed unless SDG&E curtails beyond the adopted reliability standards. ORA argues against a SIC, but states that if it is adopted, the rate should be decided in the next BCAP. We retain the $.25 per therm SIC with an annual cap of $5 million.

3. SDG&E urges the Commission to increase the deposit for pre-construction activities to 100% of forecasted pre-construction costs. We retain the 20% per customer deposit espoused in the proposed decision.

4. SoCalGas agrees with our classification of the Line 6900 expansion as a common-use facility. SoCalGas, however, contends that since it cannot recover expansion costs from its customers before 2006 due to provisions in the CSA prohibiting rate changes, A.L. 2966 should be approved. We retain the classification of Line 6900 expansion as a common-use facility and order SoCalGas to withdraw A.L. 2966 as it erroneously allocates expansion costs solely to SDG&E's customers until the termination of the CSA.

5. SoCalGas and SCGC note that the cost allocation of Line 6900 on an equal cents per therm basis is somewhat different than the Commission has used in the past for common-use local transmission facilities. SoCalGas asks that we defer the methodology used to allocate cost of Line 6900 as a common-use facility to the BCAP. We concur and have modified the decision accordingly.

6. SoCalGas notes that the new capacity from recent expansions, with the exception of Line 6900, has been on its backbone capacity expansions do not generally change the amount of firm capacity available on local transmission lines. We modify the decision accordingly.

7. SoCalGas requests that the Commission provide additional direction regarding new open seasons in the northern San Joaquin Valley and the southern Imperial Valley and we have done so.

8. Sempra Energy Resources requests that the Decision be corrected to reflect the participation of both Sempra Energy and SER and we have done so.
9. Sempra Energy Resources requests that the decision specify that the form a commitment for service may be either an open season, or a written commitment from a customer and we will allow this.
10. Sempra Energy requests revision of the affiliate transaction discussion in the decision. We find no revision necessary.
11. Cabrillo I, LLC and Cabrillo II, LLC states that firm receipt point rights established in the CSA must be in place, and that SDG&E must have a system of tradable rights before an open season can be conducted. The term of the open season on SDG&E's system was limited to two years for these reasons.
12. TURN and SoCalGas noted that the Proposed Decision incorrectly stated that the GIR unbundles local gas transmission systems. The decision has been modified to correct this error.

Assignment of Proceeding

Carl Wood is the Assigned Commissioner and Carol Brown is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Investigation 00-11-002 was prompted by high gas demand during the summer of 2000 that threatened gas curtailments for SDG&E's noncore customers.

2. SDG&E began gas service to a new EG in Rosarito, Mexico, in June of 2000, straining its system's capacity.

3. The OII was expanded to include an investigation into the adequacy of SoCalGas's gas transmission system to serve the needs of its customers within its service territory.

4. On December 11, 2002, the Commission issued D.01-12-018, in I.99-07-003, the Gas Industry Restructuring Proceeding, that adopted, with modifications, a comprehensive settlement. This decision resolved some pending issues in Phase II of this proceeding.

5. A key component of the future planning and system expansion plans of SDG&E is the reliability standard adopted for firm noncore customers, including EGs.

6. The reliability standard is connected to cost allocation issues and system expansion concerns, and determines the amount of excess capacity that is available on the system.

7. On June 7, 2000, the Commission issued D.01-06-008 establishing an interim order changing the curtailment protocol for noncore commercial and industrial customers and EGs.

8. SDG&E should be authorized to limit firm noncore service to firm capacity on its system, and to charge different rates for firm and interruptible service, to ensure that customers opting for, and paying for, firm service receive firm service.

9. Open seasons are a vehicle to allocate firm noncore capacity between existing customers, incremental new load of existing customers, and new customers.

10. The GIR decision created a structure of unbundled, firm, and tradable backbone transmission rights on SoCalGas' system that eliminated the need to consider receipt point capacity allocation in this proceeding.

11. Curtailment credits are an effective measure to motivate a utility to plan its system capacity and increase its service reliability.

12. Long-term contracts, when coupled with a system of tradable rights, would allow SDG&E to better its resource planning, but the record does not support the Commission's authorization of tradable rights at this time.

13. There is a two-to-four year lag period between the time a need for additional capacity is identified and the time the system is expanded and the capacity becomes available.

14. SDG&E's past planning of its gas transmission system did not prove adequate to meet its 1-in-5-reliability standard as evidenced by 17 days of curtailed service between November 2000 and March 2001.

15. The record does not permit the Commission to decide absolutely whether Sempra allowed its corporate affiliate interest to affect or influence SDG&E's service and system expansions, including the Baja Norte pipeline.

16. The Commission needs to establish a planning criteria and a reliability standard for SoCalGas.

17. SoCalGas A.L.s, 2966, 3002, and 3029 are all moot and no longer timely because of the passage of time and are to be withdrawn.

18. Line 6900 is a common-use facility and the costs allocation mechanism is to be decided in the next BCAP.

Conclusions of Law

1. It is reasonable to establish a 1-in-10, cold year conditions, reliability standard for firm noncore customers in SDG&E's service territory to ensure that the utility can meet the needs of its core and noncore customers.

2. D.01-06-008, issued June 7, 2001, as an interim order changing the curtailment protocol for commercial, industrial, and EG customers, is now adopted, as the permanent order for changes to Rule 14.

3. SDG&E should be authorized to conduct an open season for the allocation of firm capacity, following the protocols set forth in this decision, to determine system expansions necessary to maintain a 1-in-10 standard for all firm noncore customers.

4. It is reasonable to adopt a service interruption credit for SDG&E, with the same properties as SoCalGas' former Rule 23, to encourage SDG&E to increase and maintain service reliability.

5. The record does not support the authorization of tradable rights at this time, but if SDG&E wants to pursue long-term contracts, it can file an application for tradable rights setting forth a mechanism for management of those rights.

6. Upon receipt of a written notice of interest in firm service, SDG&E is authorized to undertake a system expansion following the procedures set forth in this decision so as to avoid a long lag period between notice of need for increased capacity and completion of the expansion.

7. SDG&E, and other affected parties, should address the resource plan for the utility in the next appropriate proceeding to ensure that the demands on the system will be met within SDG&E's newly adopted reliability standard for firm noncore service of 1-in-10, cold year conditions.

8. We do not find evidence of abuse of the affiliate rules between Sempra and its affiliates but find that the close integration between Sempra and SDG&E may have influenced SDG&E's judgment in planning for system expansions within the utility's service territory.

9. The GIR decision created a structure of unbundled, firm, and tradable backbone transmission rights on SoCalGas' system that eliminated the need to consider receipt point capacity allocation in this proceeding.

10. It is reasonable to establish a system planning criteria for SoCalGas of 1-in-35 for core customers, 1-in-10 for noncore customers, and to retain the 1-in-35 for core customers for local transmission.

O R D E R

IT IS ORDERED that:

1. A 1-in-10, cold year condition, reliability standard for firm noncore customers in San Diego Gas & Electric (SDG&E's) service territory is adopted.

2. The changes to Rule 14 set forth in the interim order issued June 7, 2001, in Decision 01-06-008, are adopted, with modifications, as the permanent order.

3. SDG&E shall offer a customer interruptible service at an interruptible rate if there is insufficient capacity on SDG&E's system to offer the requesting customer firm service.

4. SDG&E shall conduct an open season for the allocation of firm capacity, following the protocols set forth herein.

5. A service interruption credit for SDG&E is adopted as set forth herein.

6. SDG&E shall undertake system expansions upon written notice of interest in firm service following the procedures set forth herein.

7. SDG&E shall address its gas resource plan in the next appropriate proceeding to ensure that its system is adequate to meet the demands for capacity and to meet the newly adopted reliability standards.

8. The rate level and rate design for firm and interruptible rates will be decided in the next BCAP.

9. SDG&E shall submit a report on its capacity planning, demand forecast, and the status of its expansion projects to the Energy Division with the first report due on October 30, 2002, and subsequent reports following every six month thereafter. This report must contain information regarding all requests for firm service that SDG&E was unable to provide and for which it offered interruptible service at interruptible rates instead.

10. The reliability standard of 1-in-35 for core customers, 1-in-10 for noncore customers, and 1-in-35 for core local transmission customers is adopted for Southern California Gas Company (SoCalGas).

11. Line 6900 is classified as a common-use facility. The cost allocation mechanism will be decided in the next BCAP.

12. Order Instituting Investigation 00-11-002 is closed.

This order is effective today.

Dated November 21, 2002, at San Francisco, California.

LORETTA M. LYNCH
President
HENRY M. DUQUE
CARL W. WOOD

MICHAEL R. PEEVEY
Commissioners

Commissioner Geoffrey F. Brown, being necessarily absent, did not participate.